

Well Engineering and Production Operations Management System

Casing Design Manual

Approved by:

WEPO – Well Engineering Manager

Signed _____

Date _____

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1 INTRODUCTION AND PURPOSE

This document, one of the Well Engineering and Production Operations (WEPO) technical control documents, contains the BG Group policies and standards to be adopted for well casing design. The objective is to ensure that there is a consistent approach to the safety critical aspects of casing design methodology throughout the BG Group.

Casing design is a stress analysis procedure to produce a pressure vessel, which can withstand a variety of external, internal, thermal and self weight loading. It is an integral and key part of the total well design process. The ideal casing design for any particular well, is one that is the most economic over the entire life of the well without compromising safety and the environment.

Policy requirements in this document are mandatory, not discretionary, and are designed to manage operations that impact high-risk events. A violation of, or non-compliance with, policy could jeopardise safety, health, environment, cost or quality. Any deviation from policy shall have written dispensation.

The Standards provide senior management with the necessary assurance that policy has been complied with. Standards are not mandatory. However if they are not used, policy compliance shall be demonstrated in other ways.

Guidelines are discretionary and represent the currently accepted best practice for a particular operation to give the highest probability of success. Accountability for deviation from guidelines rests with the individual.

If on an individual well basis, a departure from any policy is considered appropriate, then dispensation can be requested from the BG Group Well Engineering Manager. The procedure for seeking dispensation from policy is given in Section 2.4 of the Well Engineering Policies and Guidelines Manual **(WEPGM 01)**. Dispensation may be requested and approved either for a single well or a number of wells in the same field. It must not be assumed to apply to other situations unless a similar specific dispensation has been sought and approved.

Suggestions for the amendment and improvement of this document are welcome and can be made by completing the form contained in Appendix 1 of the Well Engineering Policies and Guidelines Manual and returning it to the TVP Well Engineering Manager.

2 RESPONSIBILITIES

All personnel engaged in BG Group well engineering operations shall be familiar with the contents of this document and are responsible for compliance.

Casing design shall be carried out by a competent engineer and approved by line management to provide a robust audit trail.

BG Group Asset Managers, through their appointed Project Operations Managers shall be held accountable for compliance.

Where operational project management is contracted out to a project management contractor, the appropriate Asset Well Engineering Manager shall be responsible and

accountable for ensuring that the project management contractor is in compliance with this policy document.

The Use of Proprietary Software

Software tools exist for use by engineers to implement the policies in this manual. The use of such software saves time, can reduce the scope for errors and ensures consistency. The software should be approved by the Asset Project Manager, licensed for use by BG Group and comply with IT policies.

3 CASING DESIGN POLICIES

3.1 General Casing Design Policy

A casing design document shall be prepared for all wells taking into account all of the anticipated well parameters and the future purpose of the well, through to its final abandonment.

3.2 Casing Design Policy Statements

1) All wells, except HPHT wells, shall be designed using the following methods:

   - Uniaxial burst
   - Uniaxial collapse
   - Uniaxial tension

2) All casing designs shall ensure that the correct casing connections are utilised based on the anticipated well condition to ensure that coupling integrity will not affect the overall well integrity.

3) Casing setting depths shall be designed to ensure that the minimum predicted fracture pressure in each open hole section is greater than the maximum load predicted from all expected well operations.

4) The conductor setting depth shall provide sufficient strength to allow circulation of the heaviest anticipated mud weight in the next hole section and support the loads from the wellheads, BOPs and additional casing strings, if applicable.

5) Kick tolerances shall be calculated for all surface and intermediate casings for all wells and the following minimum kick tolerances shall be maintained:

Hole Sizes (inches)	Minimum Kick Tolerance (bbl)
23” hole & larger	250
Below 23” & to 17-1/2”	150
Below 17-1/2” & to 12-1/4”	100
Below 12-1/4” & to 8-1/2”	50
Smaller than 8-1/2”	25

6) Kick tolerances shall be re-calculated during drilling operations. Should the actual tolerance fall below the calculated minimum, then either corrective measures shall be taken (e.g. revised shoe depth), or a dispensation sought.

7) Casing pressure tests shall be specified in all well programmes and should be based on the standards in Section 5.

8) The reduction in casing strength due to casing wear shall be considered during casing design, planning of drilling and well testing operations in accordance with the standards in Section 8.

4 CASING DESIGN STANDARDS

4.1 Minimum Load Cases

The following summarises the load cases that should be considered.

4.1.1 Installation Loads

- Running casing
- Cementing operations

4.1.2 Drilling Loads

- Maximum mud weight and the temperature in the next hole section
- Casing pressure testing
- Well control situations
- Lost circulation
- DST operations (see production loading)
- Collapse loads due to formation movement

4.1.3 Production Loads

- Tubing leak at or near to the surface
- Pressure testing during completion operations and routine production operations
- Collapse loads due to completion fluids, leaks or other operations
- Collapse loads below production packers or leaks
- Collapse loads due to formation movement
- Loads due to production operations (gas lift, ESPs, stimulation, injection, jet pumps etc.)
- DST pressure testing
- DST – fluids to surface

The load cases contained in Table 4.1 are the minimum design criteria that will apply to each casing string. The list is not exhaustive and it is the responsibility of the drilling engineer to ensure that all loads the casing will be subject to during the life of the well are addressed.

Table 4.1 Conductor Casing Design Loads

Load Case		Internal Pressure	External Pressure	Temperature Profile
Collapse	Full evacuation	None	MW used to set casing MW & SW if offshore	Geothermal
Burst	N/A			
Tension	Compressive load due to weight of wellhead, inner strings, BOP etc.	MW	MW	Geothermal

Surface Casing Design Loads

Load Case		Internal Pressure	External Pressure	Temperature Profile
Collapse	Full evacuation where setting depth is less than 3000' Partial evacuation for greater setting depths	None MW column to balance lowest formation pressure in next hole section or 0.465 psi/ft gradient, whichever is lower	Max MW used to set casing. MW & SW if offshore	Geothermal
Burst	Gas to Surface	Gas gradient from fracture pressure at shoe	0.465 psi/ft	Circulating
	Gas Kick	Pressure profile due to circulating out the appropriately sized kick volume	0.465 psi/ft	Circulating
Tension	Buoyant weight plus appropriate of: • Bending • Shock loading • Overpull	MW	MW	Geothermal
	Green Cement Pressure test	MW + test pressure	MW, spacer, cement column	Cementing

Intermediate Casing/Liner Design Loads

Load Case		Internal Pressure	External Pressure	Temperature Profile
Collapse	Partial Evacuation	MW column to balance lowest formation pressure in next hole section or 0.465 psi/ft gradient, whichever is lower	MW used to set casing	Geothermal
Burst	Gas to Surface	Gas gradient from fracture pressure at shoe	0.465 psi/ft	Circulating
	Gas Kick	Pressure profile due to circulating out the appropriately sized kick volume	0.465 psi/ft	Circulating
Tension	Buoyant weight plus appropriate of: • Bending • Shock • Loading • Overpull	MW	MW	Geothermal
	Green Cement Pressure test	MW + test pressure	MW, spacer, cement column	Cementing

Production Casing/Liner Design Loads

Load Case		Internal Pressure	External Pressure	Temperature Profile
Collapse	Partial Evacuation	MW column to balance lowest formation pressure in next hole section or 0.465 psi/ft gradient, whichever is lower	MW used to set casing	Geothermal
Burst	Near Surface Tubing Leak	SIWHP over packer fluid gradient	0.465 psi/ft	Production
Tension	Buoyant weight plus appropriate of: • Bending • Shock • Loading • Overpull	MW	MW	Geothermal
	Green Cement Pressure test	MW + test pressure	MW, spacer, cement column	Cementing

4.2 Minimum Casing Design Safety Factors

The Minimum acceptable casing design factors are:

- Collapse 1.0 for partial evacuation
  0.8 for complete evacuation
- Burst 1.1
- Tension 1.6
- Triaxial 1.1

4.3 Gas Gradient Assumptions

A gas gradient of 0.1 psi/ft. should be assumed for all casing design calculations above 12000'. Below 12000', a gradient of 0.15 psi/ft will be assumed.

5 CASING PRESSURE TESTING STANDARDS

All surface, intermediate and production casings/liners should be pressure tested prior to drilling out the shoe track or perforating. Test pressures will be specified in the drilling programme and will be based on an analysis of the maximum anticipated loads from all load cases.

For surface and intermediate casings/liners the minimum test pressure should be the highest of:

- The calculated surface pressure required to perform the planned leak off test plus a test margin. The recommended test margin for development wells is 0.2 ppg (0.02 sg) and for exploration/appraisal wells 0.5 ppg (0.06 sg)
- The calculated pressure for circulating out the maximum kick as used in casing design calculations

For production casing/liners the minimum test pressure should be equivalent to the shut-in tubing pressure on top of the annulus fluid. However, any additional loads that are to be placed on the casing string (e.g. operating annulus pressure controlled test tools) must also be taken into account when planning pressure tests.

Casing test pressures should never exceed the following:

- 80% of casing/connection burst rating
- Maximum working pressure of the BOP stack
- Maximum working pressure of the wellhead equipment

Production casing strings that are to be used in a well for production or injection operations must be designed and pressure tested to the maximum possible anticipated wellhead pressure.

Due consideration should be given to the following factors:

- The burst rating of the weakest casing in the string
- The density of the mud columns inside and outside the casing
- The minimum design factors assumed in the casing design
- The effect of pressure testing on casing tensile loads

Liner overlaps should be pressure tested to a minimum of 500 psi over formation leak-off pressure. A draw down test should also be performed if the future use of the well, so warrants.

Casing pressure test limits should be designed to coincide with the load cases used in the casing design. These should reflect the maximum pressure that will be seen during the lifetime of the well.

6 CASING PROCUREMENT STANDARDS

Casing and tubulars should be purchased following the BG Group Procurement Policy Statement and the Contracting and Purchasing Policy and Quality Control Framework.

Casing and other tubulars should conform to all relevant requirements of API 5CT and API 5L, as applicable. Contractors may have their own standards that conform to recognised international standards and these may also be used, where appropriate with the written agreement of the BG Well Engineering Manager.

Where the contractor is unable to comply with any of the referenced specifications, he must identify the relevant areas at time of the tender. BG may choose to call a pre-award meeting to clarify the requirements and the contractor's responses.

This specification should be issued to prospective tubular vendors. The extent to which this specification will apply when tubular vendors propose to supply "ex stock", should be agreed at the time of proposal.

7 CASING CONNECTIONS STANDARDS

BG Group standards for casing connectors are as follows:

- Completion tubing and production casing have premium connectors
- Surface and intermediate casing have proprietary threaded connectors
- Conductors have weld-on connectors, either threaded or weight-set, depending on duty

An assessment should be made of the casing connection design requirements to ensure that well integrity will not be impaired due to selection of inappropriate connections.

Buttress connections are most widely used due to their widespread availability and cost considerations.

Premium connections should always be selected for the following circumstances:

- Where long-term leak resistance is required such as production strings, gas lift production wells etc.
- For corrosion resistant applications
- High pressure and high temperature wells
- Exploration and appraisal wells where the objective is gas or condensate or where the well could be used for long term production.

Casing connection damage should be minimised in the field by adopting best practice thread protection techniques.

8 CASING WEAR STANDARDS AND GUIDANCE

Casing wear and consequent reduction in casing strength should be considered during the planning of drilling and well testing operations.

On directional, appraisal and development wells, where the production casing is exposed to the risk of excessive casing wear, beyond the original design criteria, a casing calliper/wall thickness log should be run prior to completing/suspending the well.

When drilling below a BOP stack, a ditch magnet should be suspended in the flowline or header box.

On vertical appraisal and development wells where the main hole section is to be cased off with a liner, any metal recovered from the ditch magnet should be weighed and reported each tour and recorded with the number of string K-revs and side force at doglegs. If excessive metal is recovered from the ditch magnet, a casing calliper/wall thickness log should be run prior to completing/suspending the well.

Drill pipe with hardbanding on tool joints should not be used unless the hardbanding is ground down flush to a smooth finish, with the tool joint OD

In the case of long hole sections with long drilling periods (in excess of 30 days) a casing wear risk assessment should be carried out. The following guidance is applicable:

- Reduce severity of hole angle changes
- Monitor wall thickness (calliper survey)
- Record wear using ditch magnets
- Use of turbines
- Increase the wall thickness of the casing

If abnormal/excessive casing wear is expected, a suitable baseline casing calliper log should be run prior to drilling out float equipment. If casing wear is experienced, casing calliper/wall thickness logs should be run, to determine the extent of the wear.

When drilling out shoetracks with mud motors, the flow rate should be kept as low as practically possible to minimise casing wear. When drilling out shoetracks with rotary assemblies, use low WOB and RPM. Low rotary speeds should be maintained until all stabilisers are below the shoe.

If circulating at the shoe with a mud motor/turbine in the string, the bit should be placed below the casing shoe.

Correctly sized and spaced non-rotating drillpipe/casing protectors may be utilised, although their effectiveness is questionable.

9 CASING DESIGN GUIDANCE

9.1 Data Required for Design

Data collection must be carried out at an early stage in the design process, by means of a multidisciplinary team including petroleum engineering and operations staff in addition to the casing designer.

A key component in developing the casing design for a well is the geo-technical document. This should ideally be completed before a well plan and casing design are generated and contain the following information:

- Type of well
- Well location – onshore, water depth (if offshore), objective depths etc.
- Geological information – formation tops, faults, structure maps etc.
- Pore pressure, fracture pressure and temperature profile
- Directional well plan
- Offset well data – casing schemes, geological tie-in, operational problems, mud weights etc.
- Hazards - shallow gas, faults etc.
- Evaluation requirements
- Hydrocarbon composition – gas or oil, corrosion considerations
- Anticipated producing life of well and future well intervention
- Tubing and downhole completion component sizes
- Annulus communication, bleed off and monitoring policies, particularly for development wells
- Constraints – licence block/lease line restrictions

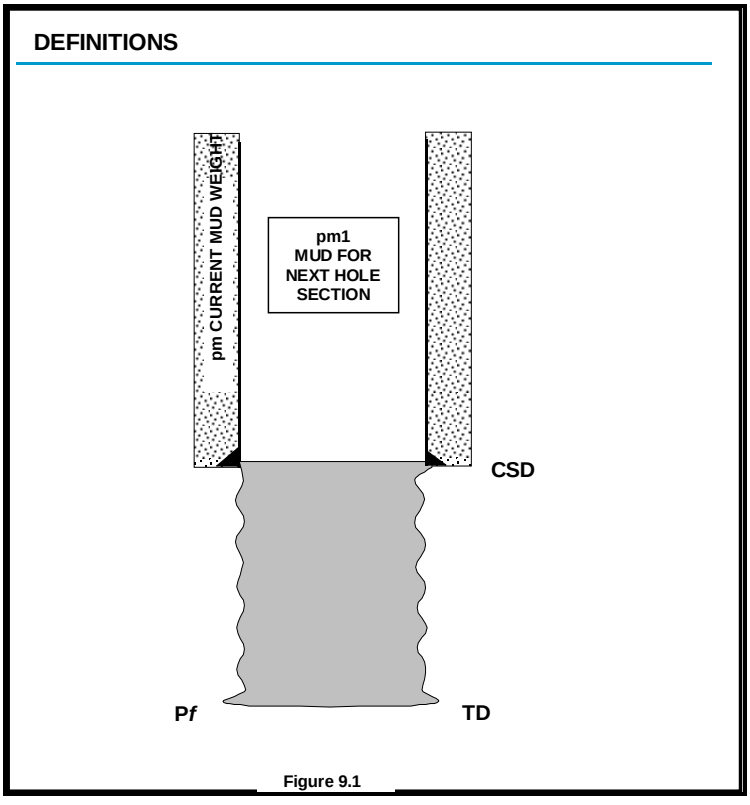
Also to be considered in the design are any constraints due to rig capabilities, casing stocks, import restrictions etc.

9.2 Casing Design Principles

Referring to Figure 9.1, below, let:

Vertical setting depth of casing	=	CSD
Vertical TD of next hole	=	TD
Formation pressure at next TD	=	Pf
Mud weight to drill hole for current casing	=	*p*m
Mud weight to drill hole for next casing	=	*p*m1

Figure 9.1 – Definitions



9.3 Casing Design Calculations

9.3.1 Collapse Calculations

9.3.1.1 Conductor

Assume complete evacuation so that internal pressure is zero. The external pressure is caused by the mud in which the casing was run.

Collapse pressure at mud line = external pressure due to a column of seawater from sea level to mud line

= (0.465 psi/ft) x mudline depth

= C1 (psi)

Collapse pressure at casing seat = C1+ 0.052 x *pm* x (*CSD*-mud line depth)

.....(1)

= *C*2 (psi)

9.3.1.2 Surface Casing

If casing is set above 3000 ft, assume full evacuation and use the following equation:

Collapse pressure at casing seat = C1+ 0.052 x *pm* x (*CSD*-mud line depth)

If casing is set below 3000 ft, assume partial evacuation and use the equation for intermediate and production casing.

9.3.1.3 Intermediate and Production Casing

See Section 13 for temperature de-rating considerations when considering collapse.

Complete evacuation in intermediate and production casing is virtually impossible, because during lost circulation, the fluid column inside the casing will drop to a height such that the remaining fluid inside the casing just balances the formation pressure of the thief zone (see Figure 9.2). Predicting the depth of the thief zone in practice is difficult. Using the TD of the next hole section represents the worst case situation and this depth should normally be used.

Assuming that the thief zone is at the casing seat, then:

External pressure at shoe = $CSD\,x\,0.465$

Internal pressure at shoe = $L\,x\,pm1\,x\,0.052$

Where:

pm	=	density of mud in which casing was run (ppg)
*p*m1	=	mud density used to drill next hole (ppg)
pf	=	formation density of thief zone, (psi/ft) (or pg)

L = (assume = 0.465 psi/ft for most designs) length of mud column inside the casing

$$L = \frac{CSD \, x \, 0.465}{0.052 \, x \, pm1} \quad \text{.....(3)}$$

Depth to top of mud column = $CSD - L$ .....(4)

Three collapse points will have to be calculated.

Collapse pressure, *C* = external pressure - internal pressure

1 Point A (at surface)

*C*1 = Zero

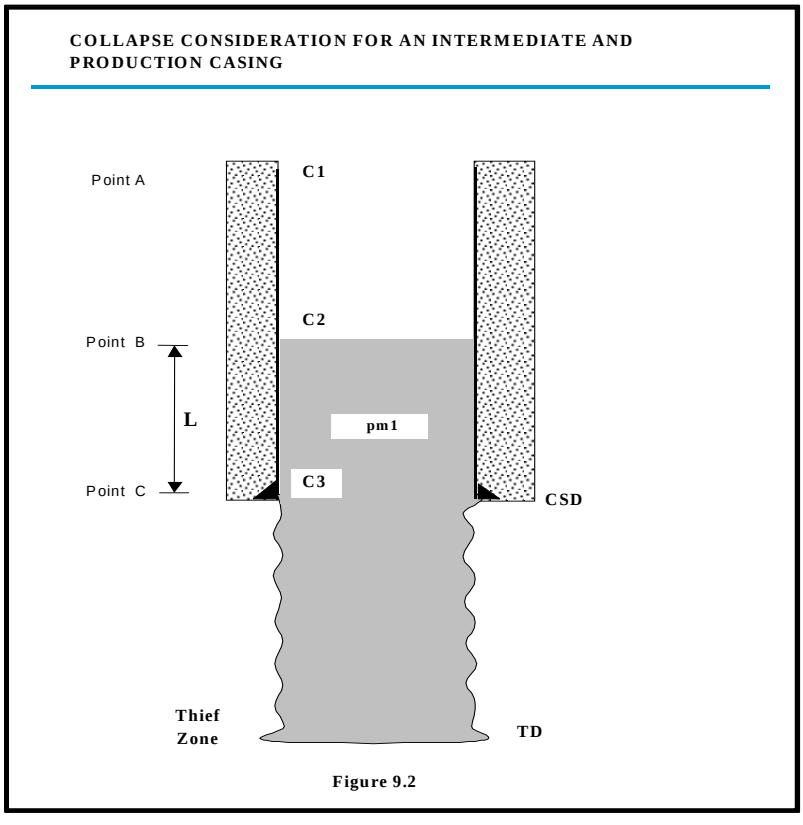
2 Point B (at depth *(CSD-L)*) = $0.052(CSD - L)x \; pm - 0$

$$C2 = 0.052(CSD - L)pm \quad \text{....(5)}$$

3 Point C (At depth CSD)

$$CSD(C3) = 0.052 \, CSD \, x \, pm - 0.052 L \, x \, pm1 \quad \text{....(6)}$$

Figure 9.2 – Collapse Consideration for an Intermediate and Production Casing



9.3.2 Preliminary Burst Calculations

The burst loads on the casing should be evaluated to ensure the internal yield resistance of the pipe is not exceeded. Fluids on the outside of the casing (back-up) supply a hydrostatic pressure that helps resist pipe burst. The net burst pressure is the resultant.

The following situations should be considered during the drilling and production phases for burst design:

- Well influx and kick circulation
- Cementing
- Pressure testing
- Stimulation
- Testing
- Near surface tubing leak
- Injection

The most important part of the string for burst design is the uppermost section. If failure does occur then the design should ensure that it occurs near the bottom of the string. Although tension considerations influence the design of the top part of the casing, burst is the governing design factor.

Figure 9.3 – Burst Consideration for all Casings Except Production Casing

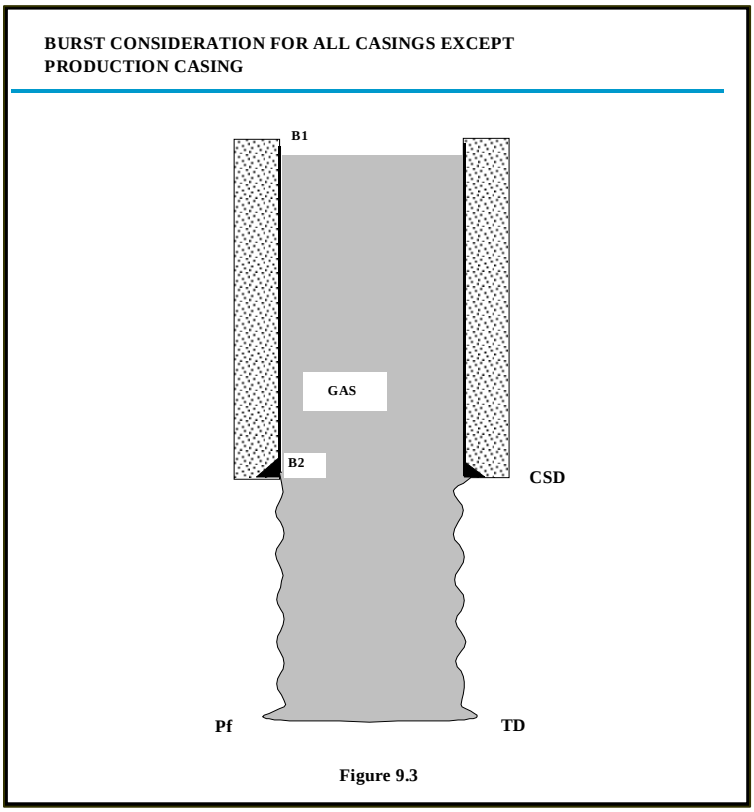


Figure 9.3

9.3.2.1 All Casing Except Production Casing - Assuming Gas to Surface

1 Calculate formation breakdown pressure at shoe

$$FBP = FG \, x \, CSD$$

Where: *FG* = fracture gradient (psi/ft)

2 Calculate the internal pressure (*Pi*) at the casing seat using the maximum formation pressure in the next hole section, assuming the hole is full of gas (see Figure 9.3, where *Pf* is considered to be at TD)

$$Pi = Pf - G\,x\,(TD - CSD)$$

Where: G is the gradient of gas (typically 0.1 psi/ft)

3 Burst pressure at surface (B1)

$$(B1) = Pf - G\,x\,TD \qquad \text{.....(7)}$$

4 Burst pressure at casing shoe (B2)

(*B*2) = internal pressure - backup load

$$= Pi - 0.465 x CSD$$

$$B2 = Pf - G\,x\,(TD - CSD) - 0.465\,x\,CSD \qquad \text{.....(8)}$$

The back-up load is assumed to be provided by mud which has deteriorated to salt-saturated water with a gradient of 0.465 psi/ft.

Note: Use available casing weights/grades if these can withstand the burst pressures *B*1 and *B*2, calculated above and collapse pressures then proceed to tension calculations.

9.3.2.2 Refinements

a) Conductor

There is no burst design for conductors.

b) Surface and Intermediate Casings

For the appropriate kick size (Section 3.2) calculate the maximum internal pressure when circulating out the kick (refer to Section 12). Calculate the corresponding values for *B*1 and *B*2.

Compare *B*1 and *B*2 with those obtained assuming the hole full of gas. For surface casing, use the highest values for burst design purposes.

For intermediate casing, use the values of *B*1 and *B*2 calculated using the appropriate kick volume.

During drilling operations the burst design is normally limited by the fracture gradient at the last casing shoe. Typically, the expected leak off pressure at the shoe with an additional margin of 1 ppg MWE is used.

9.3.2.3 *Production Casing*

The worst case occurs when gas leaks from the top of the production tubing to the casing. The gas pressure will be transmitted through the packer fluid from the surface to the casing shoe (see Figure 9.4 below).

Burst pressure = Internal pressure - External pressure

Burst at surface = $(B1) = Pf - G\,x\,CSD$ ….(9)
(or the maximum anticipated surface pressure - whichever is the greater)

Burst at shoe = $(B2) = B1 + 0.052\,pp\,x\,CSD - CSD\,x\,0.465$ ….(10)

Where:

G	=	gradient of gas (usually 0.1 psi/ft)
Pf	=	formation pressure at production casing seat (psi)
pp	=	density of completion (or packer) fluid (ppg)
0.465	=	the density of backup fluid outside the casing to represent the worst case (psi/ft)

Note: if a production packer is set above the casing shoe depth, then the packer depth should be used in the above calculation rather than *CSD*. The casing below the packer will not be subjected to the burst loading (see Figure 9.4).

Figure 9.4 – Burst Design For Production Casing

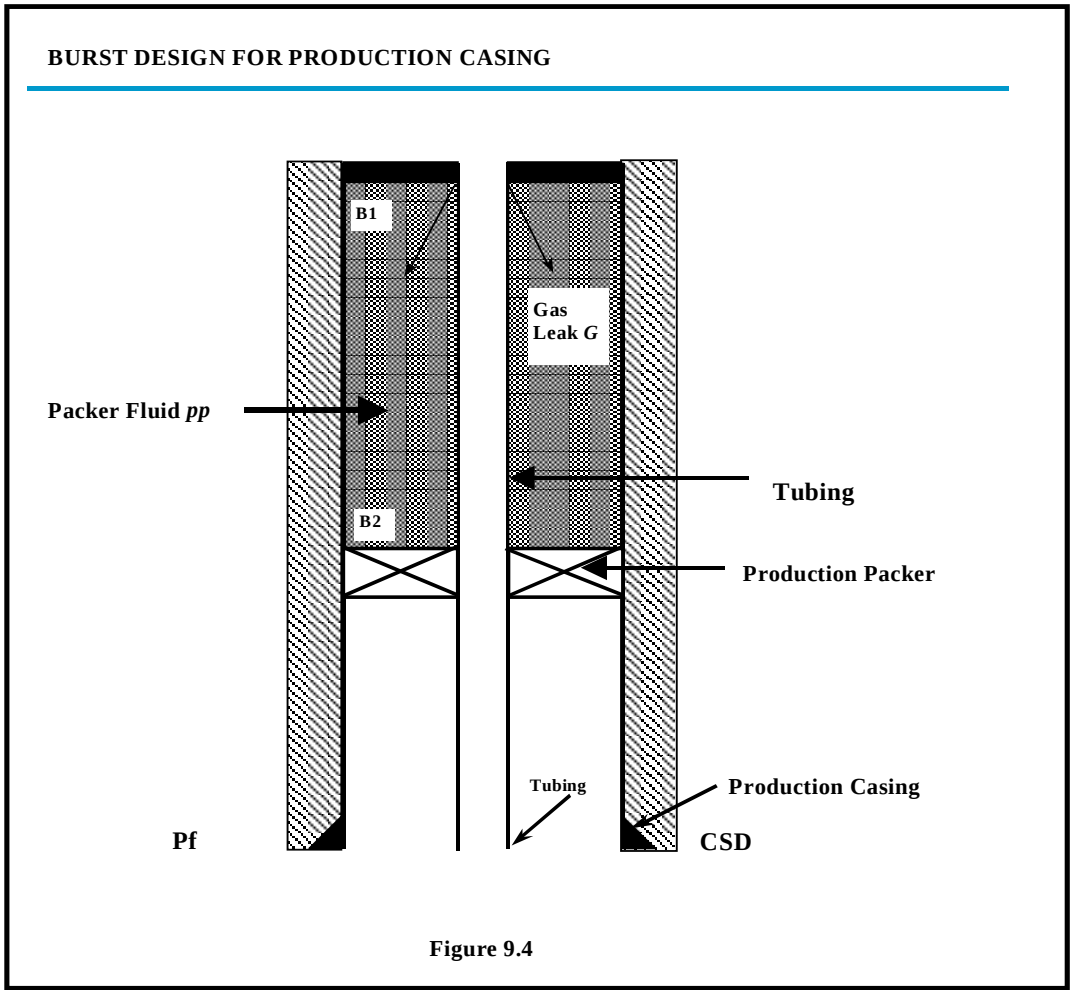
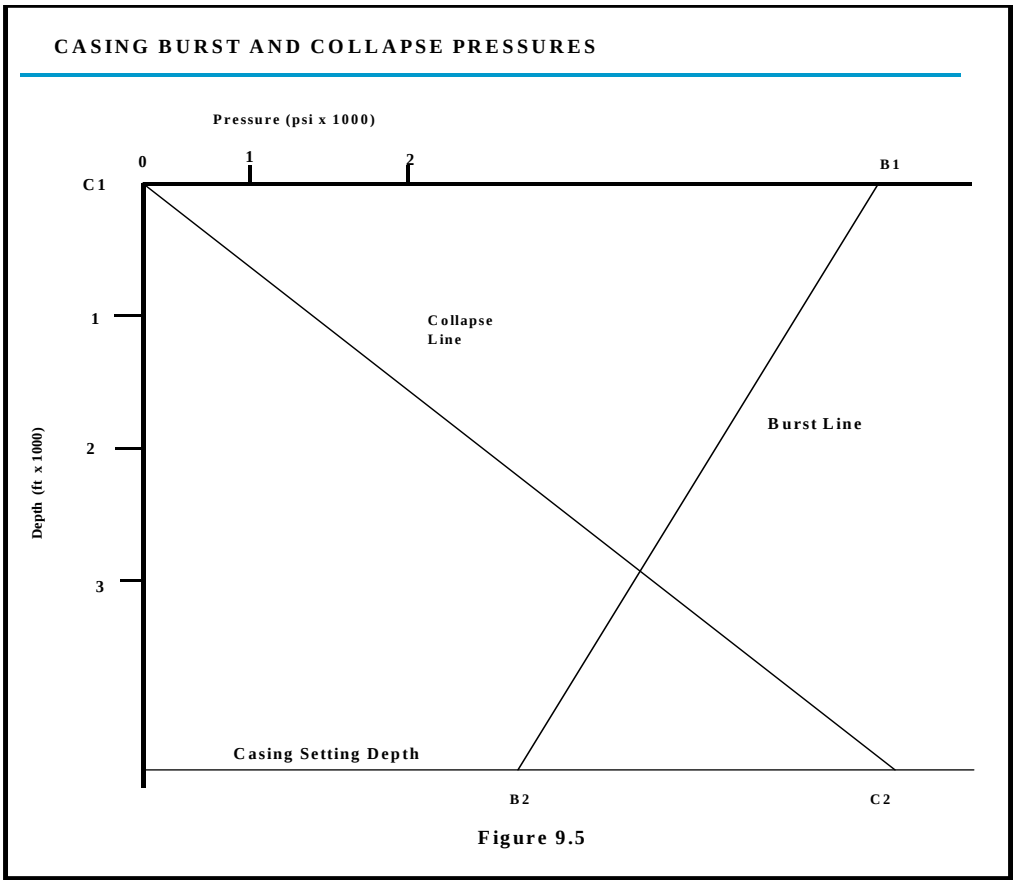


Figure 9.4

9.3.3 Selection based on Burst and Collapse

Figure 9.5 – Casing Burst and Collapse Pressures



1. Plot a graph of pressure against depth, as shown in Figure 9.5 above, starting the depth and pressure scales at zero. Mark the *CSD* on this graph.

2. Collapse Line: Mark point *C*1 at zero depth and point *C*2 at *CSD*. Draw a straight line through points *C*1 and *C*2.

   For intermediate casing, mark *C*1 at zero depth, *C*2 at depth (*CSD-L*) and *C*3 at *CSD*. Draw two straight lines through these points.

3. Burst Line: Plot point *B*1 at zero depth and point *B*2 at *CSD*. Draw a straight line through point *B*1 and *B*2 (see Figure 9.5). For production casing, the highest pressure will be at casing shoe.

4. Plot the adjusted collapse and burst strength of the available casing, as shown in Figure 9.6 below.

$$\textit{(Adjust strengthened} = \frac{\textit{manufacturer's value}}{\textit{Safety factor}}\textit{)}$$

5. Select a casing (or casings) that satisfy both collapse and burst. Figure 9.6 provides the initial selection and in many cases it differs very little from the final selection. Hence, great care must be exercised when producing Figure 9.6.

Fig 9.6 Preliminary Casing Selection Based On Burst and Collapse

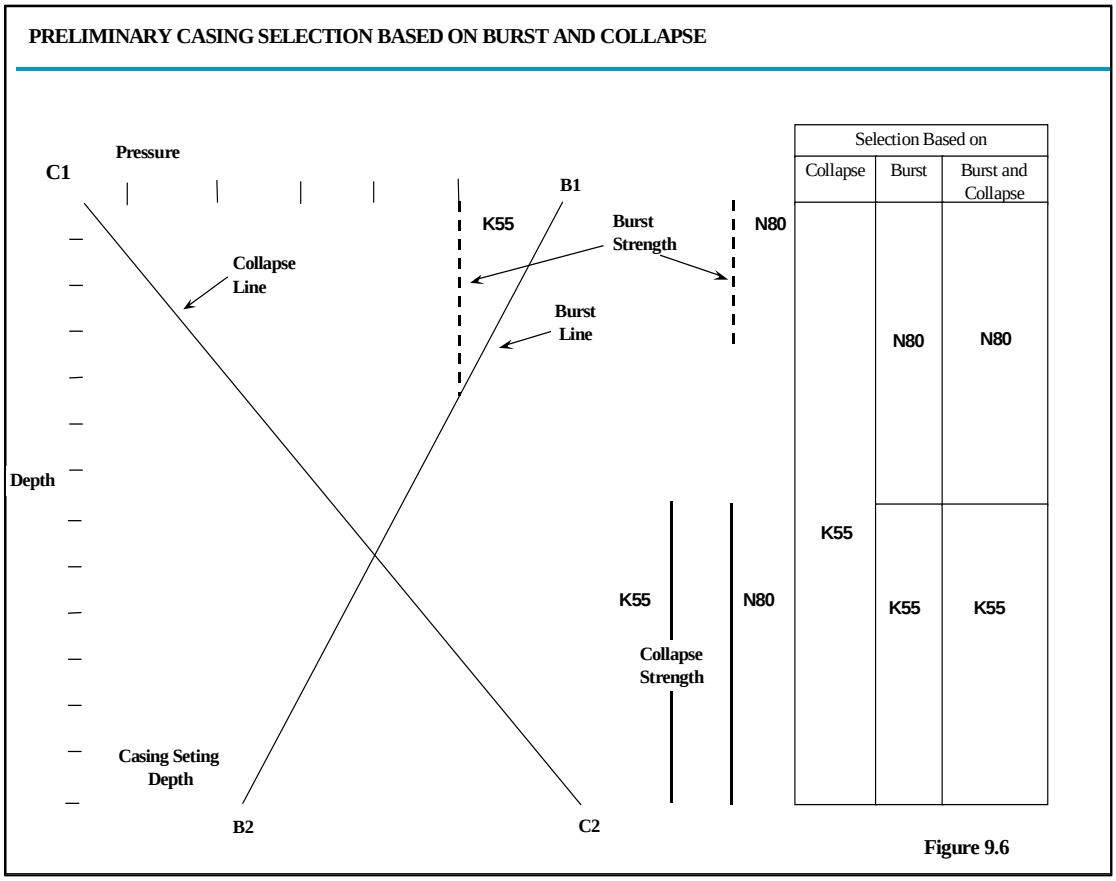


Figure 9.6

9.3.4 Tensile Design Guidance

The total tensional load at any time is the sum of forces due to:

- The weight of the casing in air
- Buoyancy
- Bending
- Drag or shock loading (whichever is the greater)
- Casing test pressures

Bending forces should always be evaluated and the appropriate DLS used. (See Dog Leg Severity Guidelines in the BG Group Directional Design and Surveying Guidelines **(WSD DS 02)**.

In addition, the design must take account of drag or shock loading when running or reciprocating the string.

The design factor will vary if either all of the potential tension forces are calculated or simply hanging weight is used.

After each section of casing is selected during burst and collapse calculations, the top section is checked to be certain that it meets tensile strength requirements. If the casing is too weak, a change should be made to provide sufficient strength for least cost. This should normally be via the following method:

- A more efficient connection
- Higher grade of steel
- Higher weight of steel/foot

As with all casing design considerations, the final selection can be heavily influenced by available pipe, warehouse stock or buyback agreements from suppliers.

9.3.5 Tension Calculations

The selected grades/weights in Figure 9.6 provide the basis for checking for tension. The following forces must be considered:

1 Buoyant weight of casing (based on true vertical projection of the casing length) (positive force).

2 *Bending force* = $63WN\,x\,OD\,x\,\theta$ .....(11)

WN = weight of casing/ft (positive force)

θ = dogleg severity, degrees/100 ft

3 *Shock load (max)*= $3200\,x\,WN$ .....(12)
(Use 1500 *x WN* in situation where casing is run slowly)

4 Drag force (approx equal to 100,000 lbf) (positive force)

Because the calculation of drag force is complex and requires an accurate knowledge of the friction factor between the casing and hole, shock load calculations will in most cases suffice.

Caution

Both shock and drag forces are only applicable when the casing is run in hole. In fact, the drag force reduces the casing forces when running in hole and increases them when pulling out. However, despite the fact that the casing operation is a one-way job (running in), there are many occasions when a need arises for moving casing up the hole, e.g. to reciprocate casing or to pull out of hole due to tight hole. Hence, the extreme case should always be considered for casing selection.

The format in Table 9.1 should be used to check the selected casing for tension.

9.3.6 Selection Based on Tension

If all safety factors in Table 9.1 are equal or above 1.6, proceed to the next step. If the safety factor is less than 1.6, which usually occurs near the top of the hole, replace the chosen weight with the heaviest weight in the string and repeat the calculations shown in Table 9.2 (page 26). If the safety factor is still less than 1.6, a heavier casing may be required; consult your supervisor.

Pressure Testing

The casing should be tested to the maximum pressure for which it has been designed (together with a suitable rounding margin).

Tensile forces during pressure testing = buoyant load + bending force + force due to pressure

$$\text{Force due to pressure} = \frac{\pi}{4}(ID2)x\,test\ pressure \quad \text{.....(13)}$$

It is usually sufficient to calculate this force at the top joint, but it may be necessary to calculate this force at other joints with marginal safety factors in tension.

Once again, ensure that the safety factor in tension during pressure testing is >1.6.

$$S.F. = \frac{Yield\ strength}{tensile\ forces\ during\ pressure\ testing}$$

Table 9.1

Depth	Casing Grade	Casing Weight (lbm/ft)	Air Wt of section (lbf)	Air Wt of Top Joint x 1000 lbf	1 Buoyant Wt x 1000 lbf	2 Bending Force	3 Shock Load (SL)	Total Tensile Load (1+2+3)	SF = Yield Strength / Total Tensile Load
0 3000	N80	72	72 x 3000 = 216,000	556 (216+340)	556xBF	63xODx 72xθ	3200x 72	1+2+3	Yield N80 / 1+2+3
3000 8000	K55	68	68x(8000 -3000) = 340,000	340 0	556xBF-216 556xBF-216-340	63xODx 68xθ	3200x 68	1+2+3	Yield K55 / 1+2+3

Where:

Buoyancy factor (BF) = (1-Mud Weight, ppg / Steel density, ppg)

Steel density = 65.44 ppg

W_N = Weight of casing per foot

θ = Dogleg severity, (degrees/100 ft)

Yield Strength: The lowest of the body or joint strength should be used.

9.3.7 Triaxial Stress Analysis

The triaxial method of stress analysis should only be used if marginal safety factors are obtained. In the previous approach, pressure loads and axial loads are generally treated separately in what can be termed a uniaxial approach. In reality however, pressure loads and axial loads exist simultaneously. For instance, when a casing is

subject to a collapse loading, the stresses in the pipe will depend not only on the internal and external pressures, but also on the axial loading of the pipe.

Determination of the triaxial loading (i.e. triaxial stress analysis) requires evaluation of the radial, tangential, and axial stresses resulting in the pipe from a particular load case. Once this has been done, a triaxial stress analysis can be performed.

Radial Stress:

The radial stress, σr, is given by:

$$\sigma_r = \frac{P_i A_i - P_e P_e}{A_s} - \left(P - {}_i\, P_e\right) \frac{A_e A_i}{A_s A} \qquad \text{.....(14)}$$

Where:

Pi	=	the internal pressure
Pe	=	is the external pressure
*A*i	=	is the external cross-sectional area
Ae	=	the internal cross-sectional area
A	=	the cross-sectional area at the point of interest (usually Ae or Ai)

Tangential Stress

The tangential stress, σt, is given by:

$$\sigma_t = \frac{P_i A_i - P_e A_e}{A_s} + (P_i - P_e) \frac{A_e A}{A_{s_i} A} \qquad \text{.....(15)}$$

Axial Stress:

The axial stress, σ_a, is given by:

$$\sigma_a = F / A_s \qquad \text{.....(16)}$$

Where:

A_s	=	the casing wall cross-sectional area.
F	=	the axial loading

The triaxial stress, known as the Von Mises Equivalent stress, σV_{ME}, is then given by:

$$\sigma_{VME} = \frac{1}{\sqrt{2}} \left[(\sigma_a - \sigma_t)^2 + (\sigma_t - \sigma_r)^2 + (\sigma_r - \sigma_a)^2\right]^{1/2} \text{.....(17)}$$

This is then compared to the material yield strength, σ_y.

The triaxial safety factor is then:

$$\text{S.F.} = \frac{\text{material yield strength}}{\text{triaxial stress}}$$

Analysis Procedure

For triaxial stress analysis of the casing at surface being subjected to a burst loading. For example, the analysis procedure is as follows:

a) Calculate σ_r at the internal radius (A = Ai) using:

Pi = Ps (surface burst pressure)
Pe = 0

b) Calculate σt at the internal radius using the same data.

c) Calculate the axial stress at surface from:

$$a = \frac{\text{buoyant weight at surface.}}{(A_e - A_i)}$$

$$\sigma_a = \frac{\text{buoyant weight at surface}}{A_c - A_i} \quad \text{.....(18)}$$

d) Calculate σ_{VME} at the internal radius and determine the resulting safety factor.

e) Repeat steps a) to d) above at the external radius ($A = A_e$).

The data input is based on the final selected grades/weights.

9.3.8 Biaxial Corrections

In the above triaxial analysis, the radial stress, σr, is usually small in comparison to the axial and tangential stresses, and can be neglected. For a given axial stress, an equivalent yield strength can then be calculated and used in the equations for burst and collapse. This correction is only significant when axial loads are high (i.e. near surface). The effect is to reduce the collapse strength and increase the burst strength.

API Bulletin 5C3 contains an equation for reducing the collapse rating in the presence of axial tension. The following summarises the procedure:

1 Calculate the axial stress (σa) at the point of interest using:

$$\sigma a = \frac{\text{axial load}}{\text{cross-sectional area}} \text{(psi)}$$

2 Calculate the reduced yield strength Ypa from

$$Y_{pa} = \left[\sqrt{1 - 0{,}75\left[\frac{\sigma_a}{Y}\right]^2} - 0.5\frac{\sigma_a}{Y_p}\right] Y_p \quad \text{.....(19)}$$

Where Y_p = initial yield strength (in psi) as given by the manufacturer.

3 Calculate the ratio D/t (OD / wall thickness)

4 From Table 9.2 (below), calculate the constants A, B, C, F and G.

5 Compare the ratio D/t for the casing in question with the various limit values given in Table 9.2, i.e. is D/t ³ 2+BA/3(B/A), etc.

6 Once the applicable D/t range is determined, the appropriate equation for calculating the reduced collapse resistance is obtained from Table 9.2.

A computer programme based on the equations given in Table 9.2 is available and can be used to calculate reduced collapse strengths.

It is sufficient to calculate the reduced collapse for the middle parts of the hole where the combined effects of tension and external pressure are most severe. Although at the surface the tension is maximum, the external pressure is zero and in theory any casing can be used for collapse purposes.

Calculate the new safety factors in collapse at the relevant sections - check 2 to 3 sections:

$$\text{S.F. in collapse} = \frac{\text{Collapse resistance under biaxial loading}}{\text{Collapse pressure at the relevant depth}}$$

9.3.9 Final Selection

The selected grades / weights should be summarised as follows:

Depth	Grade / Weight
O – X	N80 / 72#
X – Y	K55 / 68# Etc

Table 9.2 - API Minimum Collapse Resistance Equations

Failure Mode	Applicable D/t Range
1 Elastic $P_c = \frac{46.95x106}{(D/t)\,((D/t)-1)2}$	$\frac{D}{t} \geq \frac{2+B/A}{3B/A}$
2 Transition $P_t = \frac{(F - G)\,Y_p}{D/t}$	$\frac{YP}{C+YP(B-G)}\ \frac{(A-F)}{t} \leq \frac{D}{t} \leq \frac{2+B/A}{3B/A}$
3 Plastic $Pp = Yp(A - B) - \frac{[(A-2)2+8(B+C/Yp)]^{0.5}}{2(B+C/YP)} + \frac{(A-2)}{(D/t)} \leq \frac{D}{t} \leq \frac{Yp(AF)}{C+Yp(B-G)}$	
4 Yield $P_y = 2YP\,\frac{((D/t)-1)}{(D/t)2}$	$\frac{D}{t} \leq \frac{[(A-2)2+8(B+C/YP)]^{0.5}+(A-2)}{2(B+C/YP)}$

Where:

A = 2.8762 + 0.10679x10-5YP + 0.21301x10-10YP2 - 0.53132x10-16YP3

B = 0.026233 + 0.50609x10-6YP

C = - 465.93 + 0.030867YP - 0.10483x10-7YP2 + 0.36989x10-13YP3

$$F = \frac{46.95x10^6\left[\frac{3B/A}{2+B/A}\right]^3}{\left[Y_p\frac{3B/A}{2+B/A} - B/A\right]\left[1-\frac{3B/A}{2+B/A}\right]^2}$$

G = FB/A

9.3.10 Drilling and Production Liners

The design principles in collapse and burst also apply to liners. If a production liner is used, the intermediate casing must be designed as a production casing. Drilling liners need to be checked mainly for collapse, but integrity in burst must also be checked.

9.3.11 Compression Loading on 26" and 30" Casing

If the 26"/30" casings are to carry the weight of other casing strings (i.e. 13⅜", 9⅝" etc) then a check on the compressive loading should be made:

1. Calculate the total buoyant weight of all casing carried.
2. Calculate the weight of wellhead and xmas tree, or wellhead/BOPs, whichever is the largest.
3. Estimate the environmental loading.
4. Add loads 1 to 3 to obtain a total load, W.
5. Divide the yield strength by the W to obtain a safety factory, SF.
   Ensure the value of SF is greater than or equal to 1.1

(In this analysis, it is assumed that the compressive strength of steel is equal to its tensile strength).

9.3.12 Casing Stretch

The casing stretch (e) due to its own weight and radial forces is given by:

$$e = L^2 \frac{(65.44 - 1.44 x \rho_m)}{9.625 x 10^7} \quad (inches)$$

.....(20)

ρ_m = density of mud, ppg

L = length of casing, ft.

Ensure that the casing is set at least a distance (e) above the TD to prevent the casing from being subjected to compression.

10 OFFSHORE CONDUCTOR DESIGN GUIDANCE

10.1 Jack-up Drilling Rigs

The conductor is fundamental to the integrity of the well and the containment of well fluids when drilling from a jack-up rig. For this reason it is important to check the conductor design even though, in the majority of cases, a standard design may be satisfactory and neither basic calculations nor detailed analysis are necessary.

The conductor is subjected to a number of internal and external loads, which combine to cause bending, compression, buckling and fatigue:

- Wave loading
- Current loading
- Internal casing weight/pre-tension
- Self weight
- Mud weight
- Wellhead/BOP weight

Waves and current loading deflect the conductor and apply bending forces, normally greatest in the wave zone. Internal casings, wellhead, BOP and mud weight are added to give a compressive load which reaches a maximum at some point below the mudline. The combined compressive and bending forces tend to cause buckling.

Fatigue damage is caused by the fluctuating effect of wave loading and in certain current regimes by vortex induced vibration (VIV). Extreme design wave and current conditions are normally based on a 10-year return period.

The engineering skills needed to design marine conductors are much more in the areas of ocean and structural engineering than of drilling engineering. Therefore, it is always recommended that such expertise be consulted before selecting a conductor.

The actual analysis procedure consists of two main elements, as outlined in Sections 10.1.1 and 10.1.2, below.

10.1.1 Environmental Loading Analysis

Calculates the maximum force generated by the wave/current loadings using either Finite Element Analysis or Computational Fluid Dynamics.

10.1.2 Vortex Shedding Analysis

Any cylindrical body when immersed in a moving fluid will produce vortices on the downstream side of the current. The shedding of these vortices causes the body to oscillate, first in line with the direction of the current flow (in line vibrations) and then perpendicular to it (cross flow vibrations) as the fluid velocity increases.

The fluid velocities at which these vibrations occur are dependent upon the diameter and the tension regime of the conductor.

The lock on velocities of the computer model are calculated for in line and cross flow vortex induced vibration, normally using Computational Fluid Dynamics. From this the amplitude of the vibrations can be calculated an hence the applied forces and fatigue life.

10.1.3 Generation of Model for Computer Analysis

Correct information on both the well and the rig is vital in producing mathematical model for conductor analysis. It is the responsibility of the drilling engineer to ensure that both the environmental and technical data used by the contractor are correct.

List of elements required for mathematical model:-

- Water depth: Which will be known accurately from the site survey.
- Point of fixity: Inferred from site survey soil sample data or standard assumption. Also dependent upon whether the casing is to be drilled or driven.
- Height to Texas Deck : For given environmental factors, from rig contractor.
- Restraint: Points of restraint on rig both lateral and top tension (size and incident angle).
- Stack up: Weight dimensions and position of diverter, BOP etc. When they will be nippled up and how much if any of the conductor weight they will bear?
- Surface casing: Sizes and weights, clearances, design centralisation programme, MLS set up.

This information should be taken from the actual equipment used whenever possible. Incorrect approximations can seriously affect load calculations.

10.1.4 Environmental Criteria

The environmental criteria to be used for conductor design is set out in the UK Department of Energy (DoE) "Offshore Installations: Guidance on Design, Construction and Certification (1990)". These are vague, and apply to all types of offshore installation. Essentially the design wave and current values used must be between ten and fifty years.

Industry practice as accepted by Noble Denton and Vetco is:-

10 year return period maximum design current
50 year return period maximum design wave

For temporary installations it is permissible to use the environmental criteria for the period of operation alone. This would be appropriate for a jack-up rig and can considerably affect the loadings on the conductor pipe if the well is to be drilled outside the times of Spring tides.

The guidelines require a "Competent Person To Calculate Metocean Parameters" This is accepted to be a marine consultant or Noble Denton themselves will provide the data.

Maximum Waves

As per the DoE guidelines the maximum wave is that which is associated with a three hour storm. Data points are taken from the nearest offset measurement stations, usually ports, lighthouses, and offshore structures. Interpolation is then carried out from these measured values using computer modelling.

Once these maximum expected values are calculated (H_{storm}) then they are multiplied by an accepted design factor to give H_{max}, the design wave value. These design factors are included in the DoE guidelines Table 11.8 (e.g. H_S x 1.86 = H_{max}, 50 year storm) and as set out in the DoE paper, Offshore Installations: Guidance on design, construction and certification (1990).

The period for this design wave is then calculated from a modified sine wave function for the duration of the applied force.

Maximum Currents

These maximum values are interpolated from offset data in the same way. Site specific measurements are acceptable if the sample is taken over at least a month.

To produce the design current value three factors must be taken into consideration.

1) Surge Induced Current - The values for storm surge residuals are available from an Almanac and the most representative station should be used.

2) Extreme Tidal Range - This multiplier is derived from the ratio of the ranges of Highest Astronomical Tide (HAT) and the Mean Spring Tidal Range at the most representative measurement station.

i.e. $\frac{\text{HAT}}{\text{Range}}$ These values are available from an Almanac.

3) The ability to use design values specific to the period of operations is particularly useful in this respect. The HAT value changes considerably throughout the year.

4) Gross Turbulence - This is a factor applied to the smoothed maxima which appear in the almanac and is accepted to increase the current value by 20 percent.

These factors are all multiplied sequentially to the interpolated value.

$$C_{Design} = C_{Max}\ x\ Surge\ x Tidal\ Range\ x Turbulance.$$

Current Profile

A current profile is required to assess the loadings on the conductor along its full length.

Under normal circumstances the current will decrease linearly towards the seabed, where in theory it will be zero. It is sensitive to water depth Seabed topography and bottom composition. The former two are accounted for in computer interpolation. Sea bed composition is measured during the site survey. The formulae and factors for calculating current at depth accounting for sea bed composition are included in the DoE guidelines (section 11.6), in the DoE paper, Offshore Installations: Guidance on design, construction and certification (1990).

In certain areas with a non linear current profile every effort should be made to use observed data wherever possible. This is especially true for deeper water, where currents can run in different directions at different depths.

These criteria become more and more sensitive the closer the location is to a land mass. e.g. more data points from measuring stations which are closer together are required for English Channel or Irish Sea locations rather than those in the North Sea or Indian Ocean.

10.1.5 Results

If the calculations indicate that the conductor will not stand up to the environmental loads, then the casing weight, grade and external diameter can be changed to provide a suitable combination.

The analysis will also give information on the selection of the following:-

- Top tension - when and how much
- Centralisation of casing strings inside the conductor pipe
- Requirement for vortex shedding devices

10.1.6 Vortex Shedding Devices

Vortex shedding devices are used to prevent the lock-on of vortex shedding induced vibration. These can be anything fastened to the outside of the conductor pipe to disturb the flow of water.

Their position depends upon the current profile. They should be placed over the zone where the current exceeds the lock on velocity of cross flow vortex shedding. This will normally be the area below the splash zone.

It should be noted that strakes, chevrons, etc increase the drag coefficient of the conductor and must be taken into account in the load calculations. There are aerofoil-shaped vortex shedding fairings that will reduce the drag coefficient, these are expensive, difficult to fix and should only be used as a last resort.

10.2 Platform Wells

Similar issues apply to platform marine conductors as those discussed previously for jack-up rigs and as such specialist expertise should be sought in their design.

For UK operations, guidelines require that fixed structures be designed for 50-year storm conditions.

10.3 Subsea Wells

Subsea well conductor design typically consists of 4 to 6 joints of 30” x 1” wall thickness pipe. However, some wells, particularly those in deepwater, are now specified with larger OD and heavier wall pipe, typically 36” x 1.5” for the two joints immediately below the wellhead to resist potential bending loads.

The main driver on deepwater wells is to maximise the riser operating envelope and hence minimise downtime in bad weather. The additional cost of the 36” heavy wall pipe is insignificant compared to the cost of weather downtime on 4th generation deepwater rigs.

In North Sea and other similar areas with fishing activities, the conductor is dimensioned by trawl gear snagging. Trawl gear snag loads have increased as trawler sizes have increased and the use of heavier wall conductor should be considered. The soil strength should also be considered. Subsea production wells are normally fitted with trawl protection cages. The maximum potential loading on the well from snagged trawl gear, including the transmitted loads which might affect the well pressure integrity, must always be considered.

As before it is recommended that relevant expertise be consulted before selecting a conductor or well completion protection.

11 CASING SETTING DEPTH GUIDANCE

11.1 General

The initial selection of casing setting depths is based on the pore pressure and fracture pressure gradients for the well. Information on pore pressure and fracture gradients is a key factor in the design of the well and is usually available from offset

well data. This should be contained in the geotechnical information provided for planning the well.

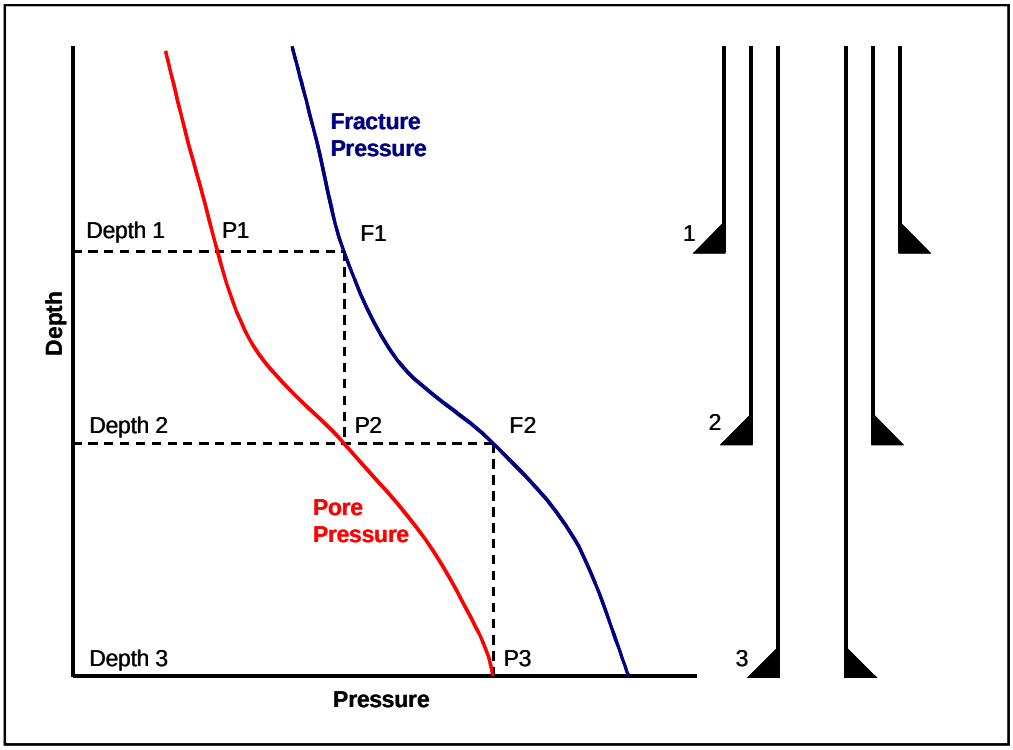
Other factors that affect the selection of casing points, in addition to pore and fracture pressures are:

- Shallow gas zones
- Lost circulation zones, which limit mud weights
- Well control
- Formation stability, which is sensitive to exposure time or mud weight
- Directional well profile
- Sidetracking requirements
- Isolation of fresh water sands (drinking water)
- Hole cleaning
- Salt sections
- High pressured zones
- Casing shoes should where practicable be set in competent formations
- Uncertainty in depth estimation (e.g. require a margin related to confidence limit when setting close to a permeable or over-pressured formation)
- Casing programme compatibility with existing wellhead systems
- Casing programme compatibility with planned completion programme
- Multiple producing intervals
- Casing availability
- Economy

Once the initial casing seats are selected, the kick tolerance should be determined for each. (See Section 12).

As the pore pressure in a formation approaches the fracture pressure at the last casing seat then installation of a further casing string is necessary. Figure 11.1 shows an example of an idealised casing seat selection.

Fig 11.1 Example of Idealised Casing Seat Selection



Notes to Figure 11.1

- Casing is set at depth 1 where pore pressure is P1 and the fracture pressure is F1
- Drilling continues to depth 2, where the pore pressure (P2) has risen to almost equal the fracture pressure (F1) at the casing seat
- Another casing string is set at this depth with fracture pressure F2
- Drilling can thus continue to depth 3, where pore pressure (P3) is almost equal to the fracture pressure (F2) at the previous casing seat

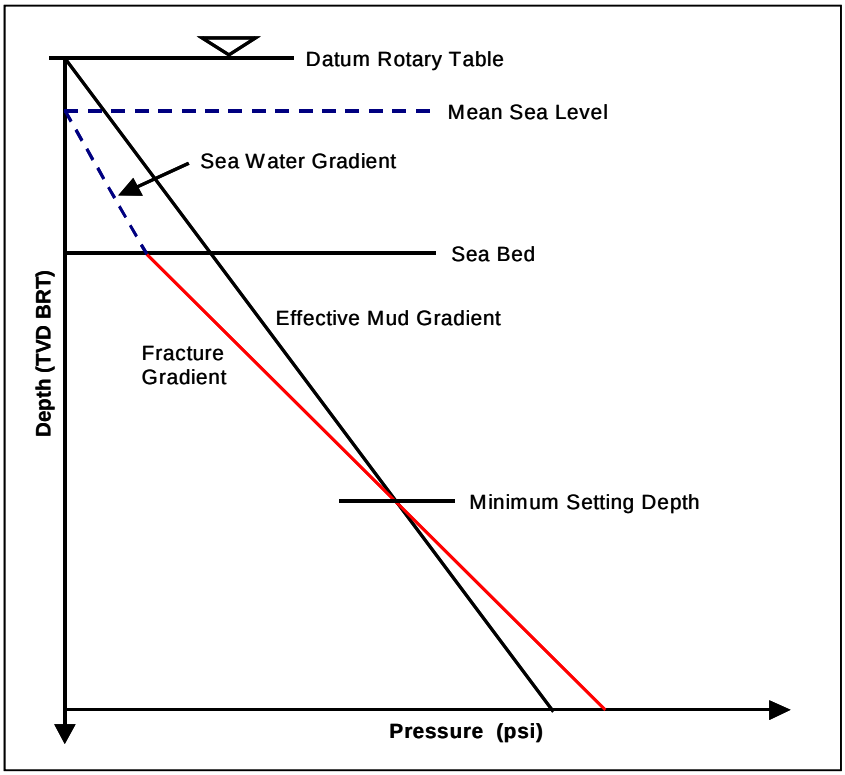
This example does not take into account any safety or trip margins, which would in practice be taken into account. The effect of hole angle on offset fracture gradient data should also be considered.

11.2 Conductor Setting Depths

Conductor setting depths should provide sufficient strength to allow circulation of the heaviest anticipated mud weight in the next hole section and to support the loads from the wellheads, BOPs and additional casing strings if applicable.

The minimum setting depth is the depth at which bottom hole pressure created by the drilling fluid being circulated (ECD) in the next hole section, is exceeded by the fracture value of the formation.

Fig 11.2 Conductor Minimum Setting Depth



The effective mud weight should take into account the weight of cuttings suspended in the mud which is dependent on drilling rates and hole cleaning. The static bottom hole density is increased by the ECD which, normally insignificant, should be taken into account in areas where lost circulation is critical.

12 KICK TOLERANCE GUIDANCE

12.1 General

Kick tolerance is defined as the maximum value of a swabbed kick that can be circulated out without fracturing the previous casing shoe. Kick tolerance therefore depends on the maximum formation pressure at the next TD, the maximum mud weight, the weakest point in the open hole (usually the previous casing shoe), the density of the invading fluid and the circulating temperatures.

Kick tolerance considerations will usually dictate that casing should be set immediately before drilling into a known high pressure zone.

When drilling exploration wells where little or no offset data exists, the well design may have to be flexible to allow casing seats to be selected based on actual measurements taken during the drilling process. Pore pressure and kick tolerance calculations made from these on site readings will then be used to determine maximum safe drilling depths for a particular hole section.

12.2 Calculating Kick Tolerance

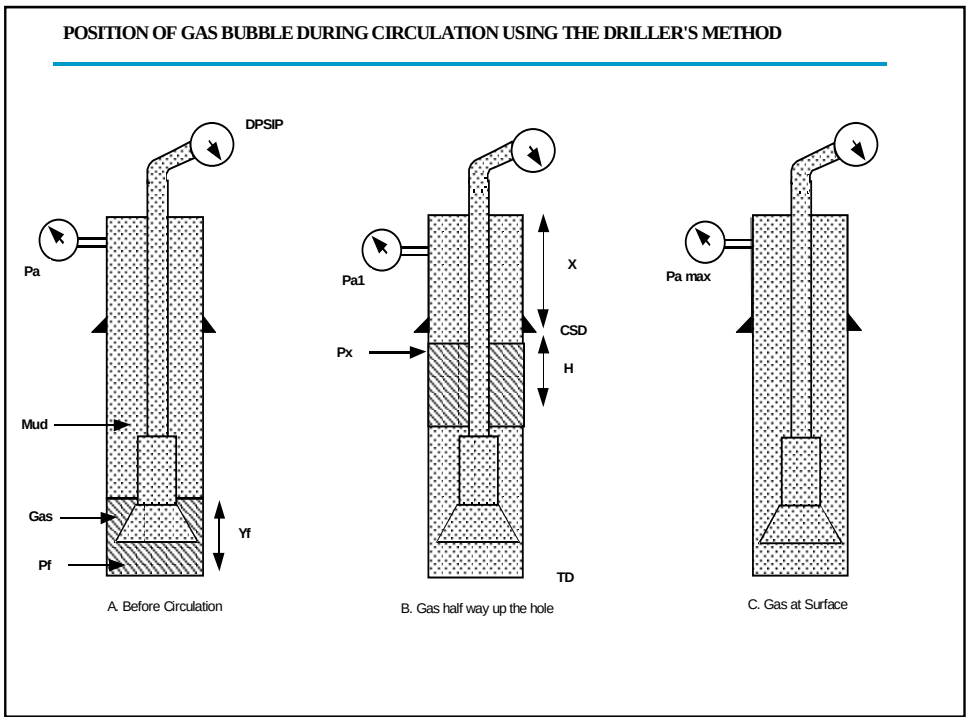
For the purpose of well design and monitoring of wells with potential kick capability, kick tolerance should be calculated in terms of:

Circulation Kick Tolerance: This is the maximum kick volume that can be circulated out without fracturing the previous casing shoe.

Additional Mud Weight over current mud weight.

Drilling Kick Tolerance: This is the maximum pore pressure that can be tolerated without the need to exceed the maximum allowable mud weight.

12.2.1 Circulation Kick Tolerance



When the top of the gas bubble reaches the shoe, the pressure at the casing shoe is given by:

$$Px = Pf - Pg(TD - H - CSD)\, x\, \rho m$$

Where:

Pf	=	formation pressure at next TD (psi)
Pg	=	pressure in gas bubble = H x G
H	=	height of gas bubble at casing shoe (ft)
G	=	gradient of gas = 0.05 to 0.15 psi/ft
TD	=	next hole total depth (ft)
CSD	=	casing setting depth (ft)
*p*m	=	maximum mud weight for next hole section (ppg)

Re-arranging the above equation in terms of H and replacing Px by the fracture gradient at the shoe (FG) gives:

$$H = \frac{0.052\, x\, \rho m(TD - CSD) + (FG\, x\, CSD\, x\, 0.052 - Pf)}{0.052\, x\, \rho m - G} \qquad \ldots.(1)$$

Where *FG* is the fracture gradient at the casing shoe in ppg

Note: In this document the Fracture Gradient (*FG*) is taken as the value recorded during leak-off tests. This is not strictly true since, during a leak-off test, the measured rock strength is the Formation Breakdown Gradient (*FBG*).

In vertical and near-vertical holes the *FBG* is invariably greater than the *FG.* In highly inclined holes the *FBG* is the usually smaller than the *FG*. For kick tolerance calculations, it is recommended to reduce the value recorded during leak-off tests by 100 psi and to use the resulting value as the *FG*.

The volume of influx at the casing shoe is:

$$V1 = H\, x\, Ca(bbl)$$

Where:

Ca = capacity between pipe and hole (bbl/ft)

At bottom hole conditions the volume of influx (V2) is given by:

$$P2V2 = P1V1$$

(The effects of T and Z are ignored)

$$V2 = \frac{V1\, x\, P1}{P2} \quad (bbl) \qquad \ldots..(2)$$

Where:

*P*1	=	fracture pressure at shoe, psi
*P*2	=	Pf, psi

The value of *V*2 is the circulation kick tolerance in *bbls*.

12.2.2 Additional Mud Weight

The maximum allowable drillpipe shut-in pressure (DPSIP) is given by:

$$DPSIP = (FG - pm)\,x\,CSD\,x\,0.052 \qquad \text{.....(3)}$$

$$\textit{Kick Tolerance} = (FG - pm) \qquad \text{.....(4)}$$

(in terms of additional mud weight)

Example 1

13.3/8" shoe	= 10,008 ft RKB
Next TD (12¼")	= 14,190 ft RKB
Fracture gradient at 133/8" shoe	= 16 ppg
Temperature gradient	= 0.02 °F/ft
Planned mud weight at TD of next hole	= 15.5 ppg
Max. formation pressure at next TD	= 14 ppg (= 10268 psi)
Gas gradient	= 0.15 psi/ft
RKB to MSL	= 85 ft

Calculate the kick tolerance at hole TD in terms of:

1) Maximum kick volume
2) Additional increase in mud weight
3) Maximum pore pressure or Drilling Kick Tolerance

Solution

Firstly, express the fracture pressure at the shoe in terms of psi:

$$FP = 16\,x\,0.052\,x\,10008 = 8326\,psi$$

Where FP is the fracture pressure in psi

Apply a safety factor of 100 psi to reduce the FP from 8326 psi to 8226 psi, or 15.8 ppg fracture gradient. Using equation (1) to calculate H gives:

$$H = \frac{0.052\,x\,15.5(14190-10008)+(8226-10268)}{(0.052\,x\,15.5-0.15)}$$

= 2025 ft

Hole capacity between 5" DP and 12¼" hole = 0.1215 bbl/ft

$V1$ = 0.1215 x 2025

= 246 bbl

At bottom hole conditions:

$$V2 = \frac{246\,x\,(8226)}{(10268)} = 197\ bbl$$

Therefore the kick tolerance in terms of maximum kick size at hole TD is 197 bbl.

Additional mud weight:

$$DPSIP = (FG - \rho m) x\, CSD\, x\, 0.052$$

= (15.8 - 15.5) x 10008 x 0.052

= 156 psi

or 15.8-15.5 = 0.3 ppg of additional mud weight

Note: These calculations do not allow for the effects of ECD.

12.2.3 Drilling Kick Tolerance

For BG Group operations the minimum kick sizes that must be maintained for routine drilling operations are contained in Policy Section 3.2 and are as follows:

Hole Sizes (inches)	Minimum Kick Tolerance (bbl)
23" hole & larger	250
Below 23" & to 17-1/2"	150
Below 17-1/2" & to 12-1/4"	100
Below 12-1/4" & to 8-1/2"	50
Smaller than 8-1/2"	25

For the above example if a maximum kick size of 100 bbls is to be maintained then the maximum allowable pore pressure at next TD is calculated as follows:

$$H = \frac{100}{0.1215}$$

= 823 ft

Solving equation (1) for *Pf* and using a mud weight of 15.5 ppg gives:

$$823 = \frac{0.052\, x 115.5 (14190 - 10008) + (8226 - pf)}{0.052\, x 15.5 - 0.15}$$

$$Pf = 11056 \text{ psi}$$

$$= \frac{11056}{(14190 - 85)\, x\, 0.052}$$

= 15.1 ppg

Drilling Kick Tolerance = Max. Pf - current estimate of *Pf*

= 15.1 - 14 = 1.1 ppg

12.2.4 Updating Kick Tolerance While Drilling

In exploration wells where the values of pore pressure and mud weight are revised constantly, it is advisable to recalculate kick tolerance as the hole is drilled.

A table of revised values for the above example may be constructed as follows:

Estimated			*Kick Tolerance*	
TVD (ft)	*Mud Weight (ppg)*	*Pore Pressure (ppg)*	*Kick Size (bbl)*	*Add. Mud Weight (ppg)*
12000	12.4	11	799	3.4
13000	12.4	12	525	3.4
13500	15.1	13	330	0.7
14190	15.5	14	197	0.3

12.2.5 Kick Tolerance Graph

For planning purposes, it is useful to construct a “Kick Tolerance Graph” as shown in Figure 12.1. In this figure, the kick volume is plotted on the X-axis (point 2), and the DPSIP is plotted on the Y-axis. Point 1 is the maximum DPSIP as calculated by equation (3). Point 2 is the maximum kick volume as obtained from equation (2) for zero drill pipe shut-in pressure. The straight line joining points 1 and 2 is called the "Kick Tolerance" graph. If the effects of temperature and gas compressibility are included then a curve is obtained.

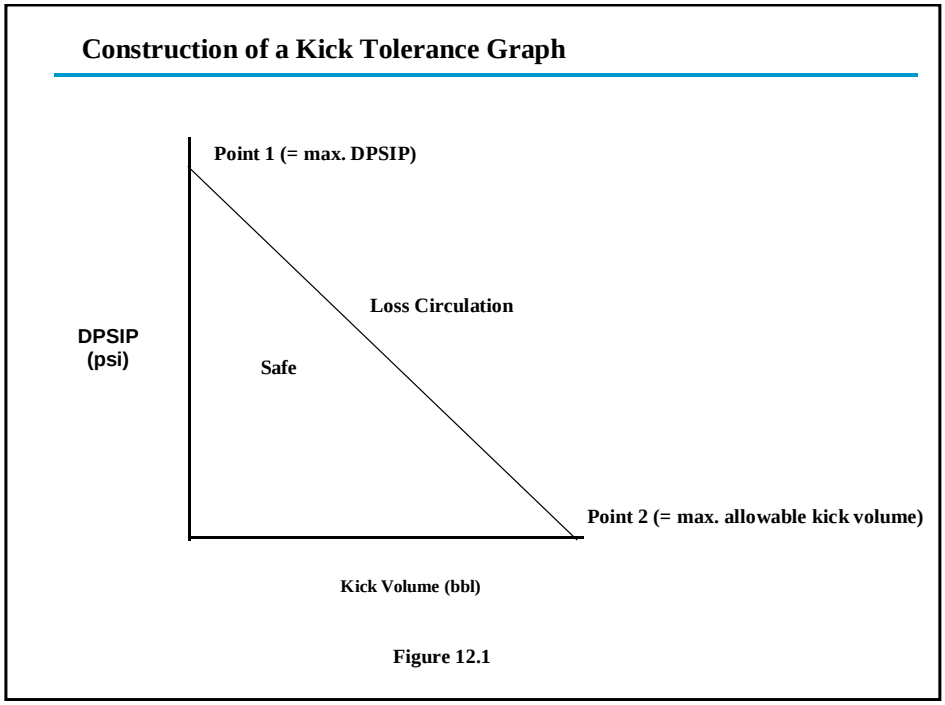


Figure 12.1

All points to the top and right of the line represent internal blowout and lost circulation conditions. Points below the line represent safe conditions and give kick tolerance for any combination of kick size and drillpipe shut-in pressure.

Note: Kick Tolerance is dependent on values of mud weight and pore pressure and the curve must therefore be updated each time these values change.

Example 2

Construct a kick tolerance graph for the well given in Example 1 at depths 13500 ft and 14190 ft.

Solution (see Figure 12.2 below)

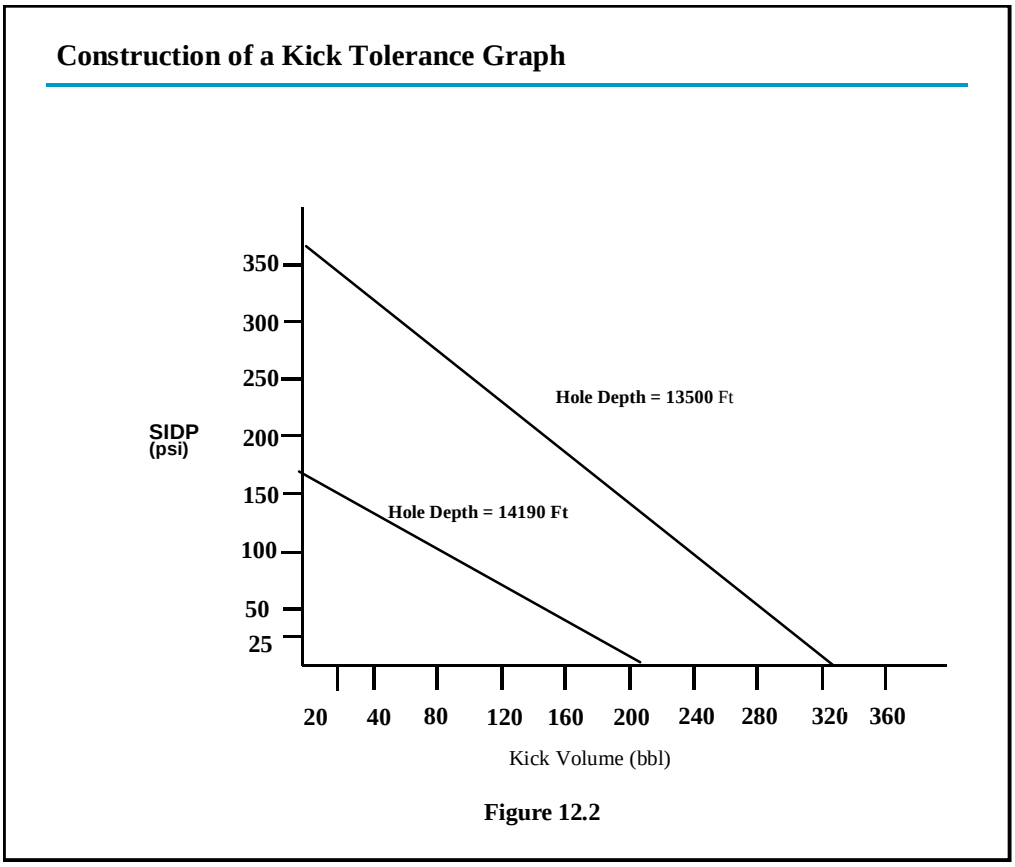


Figure 12.2

1) Maximum kick volume = 330 bbl at 13500 ft and 197 bbl at 14190 ft (point 2).
2) Maximum DPSIP = 364 psi at 13500 ft and 156 psi at 14190 ft (point 1)
3) The line joining points 1 and 2 gives the kick tolerance graph

From Figure 12.2, the following tables may be constructed to give the kick size that can be tolerated without shoe fracture.

Hole Depth = 13500 ft

Kick Volume (bbl)	*Max. DPSIP (psi)*
50	310
100	255
150	197
200	143

Hole Depth 14190 ft

Kick Volume (bbl)	*Max. DPSIP (psi)*
50	118
100	74

12.2.6 Use Of Kick Tolerance Calculations To Calculate Formation and Casing Pressures

The appropriate kick volume should be selected from the minimum kick size table (i.e. 50 bbl for 8½" hole, 100 bbl for 12¼" hole, etc.).

This is volume V2 in the above equations.

The pressure at the top of the gas bubble as it is being circulated out is then given by:

$$= 0.5\left[A + \left[A^{2} + \left[\frac{4 pf V_2 NPm}{Ca}\right]\right] 0.5\right] \quad \ldots.(5)$$

Where:

p*m* is in psi/ft

A = P*f* - p*m* (TD - X) - Pg

X = depth to top of gas bubble

N = $\frac{Zx\ Tx}{Zb\ Tb}$

Zb, Zx = Compressibility factor at bottom hole and depth X

Tb, Tx = Temperature (Rankin) at bottom hole and depth X

This pressure should be calculated at various points and compared with the formation breakdown pressure to determine if the selected casing setting depth is suitable.

The pressure when the bubble is at surface is used in casing burst design calculations.

13 TEMPERATURE CONSIDERATIONS

13.1 De-rating of Yield Strength

Both the burst and axial ratings of a casing are proportional to the yield strength of the material. The collapse rating is also a function of the yield strength but is variable depending on the D/t ratio. Minimum yield strength values for standard grades are provided in API specification 5CT and should be used as a starting point when calculating the pipe strength. However, yield strength is temperature dependant.

In most grades of low alloy steel used in the oilfield this dependence is approximately linear and can characterised as a reduction of 0.045% per °F at temperatures in excess of 68°F. There is a large amount of scatter in the yield strength reduction data provided by casing manufacturers but 0.045% per °F is a representative value. The dependence is shown in Table 13.1:

Temperature		Yield Strength Correction
°F	°C	
68	20	1.000
122	50	0.976
212	100	0.935
302	150	0.895
392	200	0.854

Table 13.1 - Yield Strength Temperature Correction

The yield reduction of 0.045% per °F is conservative and can be used for most wells without problem. However, the actual yield reductions for each casing grade are available from the casing/steel suppliers upon request and should be used if possible. This should be done for high temperature wells.

14 CORROSION DESIGN CONSIDERATIONS

Water is necessary to the corrosion process. The existence of any of the following alone, or in any combination, may be a contributing factor to the initiation and development of corrosion.

- Oxygen (O_2)
- Hydrogen Sulphide (H_2S)
- Carbon Dioxide (CO_2)

Forecasting their presence and concentration is essential for a choice of a proper casing grade and wall thickness and for operational safety purposes. Tentative forecasts can be made after data gathering and on the basis of regional occurrence maps.

Casing can also be subjected to corrosive attack opposite formations containing corrosive fluids. Corrosive fluids can be found in water rich formations and aquifers as well as in the reservoir itself.

14.1 Hydrogen Sulphide (H_2S)

The NACE definition for these "sour" conditions is an H_2S partial pressure over 0.05 psia. For a well with a bottom hole pressure of 10,000 psi, this represents an H_2S concentration of 5 ppm.

The presence of H_2S may result in hydrogen blistering and Sulphide Stress Cracking (SSC).

SSC occurs usually at temperatures of below 80°C and with the presence of stress in the material and when the H_2S comes into contact with water, which is an essential element in this form of corrosion. Higher temperatures, above 80°C inhibit the SSC phenomenon; therefore knowledge of temperature gradients is very useful in the choice of the tubular materials since different materials can be selected for different depths.

Evaluation of the SSC risk depends on the type of well. In gas wells, gas saturation with water will produce condensate water and therefore create the conditions for

SSC. In oil wells, two separate cases need to be considered, vertical and deviated wells.

In vertical oil wells corrosion generally occurs only when the water cut exceeds 15%, which is the threshold level. It is necessary to analyse the water cut profile throughout the life of the well.

In highly deviated wells (> 80°) the risk of corrosion by H_2S is higher since the water, even if in very small quantities, deposits on the surface of the tubulars.

14.2 Carbon Dioxide (CO2)

When CO_2 dissolves in water it forms carbonic acid, decreases the pH of the water and increases its corrosivity. It is not a corrosive as oxygen but usually results in pitting.

The major factors governing the solubility of CO_2 are pressure, temperature and composition of the water. Pressure increases the solubility to lower the pH; temperature decreases the solubility to raise the pH. Corrosion primarily caused by dissolved carbon dioxide is commonly called 'sweet' corrosion.

Using the partial pressure of CO_2 as a yardstick to predict corrosion, the following relationships have been found:

- Partial Pressure > 30 psia usually indicates a high corrosion risk.
- Partial Pressure 3 – 30 psia may indicate a high corrosion risk.
- Partial Pressure < 3 psia is generally considered non corrosive.

14.3 Selecting Materials for Corrosive Environments

The selection of casing to be used for sour service must be specified according to API 5CT for restricted yield strength casings. It is imperative to select the appropriate casing grade to prevent SSC. The API recommended grades are C-75, L-80 and C-95. Other propriety grades are also available and information is readily available from casing manufacturers.

14.4 Managing Corrosion

Corrosion control measures may involve the use of one or more of the following:

Control of the Environment	pH Temperature Pressure Chloride concentration CO_2 and H_2S concentration Water concentration Flow rate Inhibitors
Surface Treatment of the Steel	Plastic coating Plating
Corrosion Resistant Materials	Corrosion resistant alloy steels

15 SPECIAL DESIGN CASES

The objectives of this section are to provide the drilling engineer with sufficient understanding of the issues involved, simple calculation methods useful for front end engineering studies and preliminary designs and to provide a common starting point for both drilling and specialist design engineers from which to jointly develop the optimum tieback design for a specific project.

15.1 HPHT Wells

Because of the additional complexity of analysis, HPHT well design is most conveniently performed using appropriate casing design software for well thermal/flow analysis, and for the calculation of tubular safety factors. Most casing designs using software such as “Stresscheck” make use of in-built temperature profiles. For high temperature wells (when BHST exceeds 250°F or water depth exceeds 3000 ft) a more advanced software model such as “ Welltemp” is required.

Temperature profiles must be determined for each load case. The temperature profiles required for each casing design are:

- Static temperature
- Cemented temperature
- Drilling circulation temperature
- Producing temperature

Casing is usually held at the wellhead and by cement so that the movement is restrained. This results in forces being generated which must be considered in design. The changes in temperature impact casing designs.

The static temperature profile is the surface temperature (temperature at the mudline for offshore wells) plus the natural geothermal gradient. (^{O}F per 100 feet.). It can be calculated assuming a linear relationship between depth and temperature.

The cementing temperature profile should be calculated for bottom hole temperatures above 165^{o}. The heat transfer history of the well affects the calculation which can be analysed using “Welltemp".

Drilling Circulating Temperatures increase whilst drilling ahead and can result in casing elongation above the cement top. This can lead to helical buckling if axial compression is created.

Production temperatures are the most critical for casing and tubing designers. The production temperature profile is based on the bottom hole static temperature.

Consideration must be given to the yield de-rating of casing due to temperature degradation of yield stress. A recommended de-rating factor for low alloy steels is 0.03% per ^{o}F. This is the default profile used in “Stresscheck”.

Consideration must be given to pressure increases in sealed annuli due to temperature increases. This is particularly applicable to sealed annuli on subsea HPHT wells.

15.2 Casing Salt Sections

The homogeneous crystalline nature of salt, coupled with its plastic properties, allows it to directly transmit lateral loads equivalent to the overburden pressure. These are recognised to occur as either uniformly or non-uniformly distributed loads.

For casing designs through plastic salt sections the external pressure load should be assumed to equal the formation overburden pressure or 1 psi/ft if pressures are uncertain.

The most important factor in reducing collapse loading across salt sections is to successfully complete the cement job. A consistent cement sheath will assist in distributing the collapse load in a uniform manner.

Uniform Loading – This is the effect of the salt transmitting all or part of the overburden to the casing in a uniform manner around all of its 360° circumference and over a considerable length. This can be modelled in casing design by substituting the overburden pressure at any depth for the hydrostatic pressure. The API rating for any single casing string or combination of strings may then be used to select the appropriate casing(s).

Non-uniform Loading – This is the effect of the salt transmitting an excess pressure over a limited arc of the casing circumference and is generally thought to be over a shorter length than for the uniform case. The API rating is of little relevance in this case. Experience and calculation show that the failure of strings subject to this type of loading occurs at levels of overburden pressure below the API rating. In some cases at only 20 – 30% of its API rating. Casing collapse from the effects of salt movement can occur many years after completion of the well.

It is inevitable that in the course of casing a salt section the string will eventually be exposed to one of these types of loading. The key to long term casing integrity lies in ensuring that non-uniform loading is minimised.

Prevention of Non-uniform Loading

Regardless of the care taken in drilling the well, conditions may exist for non-uniform loading to develop. It is possible to counter these with a correctly engineered casing and cementing programme. The following are general recommendations intended to provide a competent cement sheath to distribute the load:

- Drilling a gauge hole
- Utilising high early compressive strength cement slurries
- Ensuring good cement jobs across the entire salt section. This requires good displacement techniques with slurries and spacers engineered to prevent wellbore enlargement
- Reliance should not be placed on squeeze techniques to correct poor primary cement jobs. Experience has shown that the quality of the bond required by the cement in these instances is insufficient to prevent subsequent casing problems

Enhanced Collapse Resistance

Use of high weight and grade casing is valid in some cases but the law of diminishing returns prevents the use of super heavy weights and grades in all cases.

Oversize Casing

The running of thick wall oversize strings of casing has been tried with success. The problems with this solution lie in the supply of the casing sizes required and the limited increase in collapse rating. In addition, there are difficulties running the larger ODs of such casings in highly plastic formations.

Dual Casing Strings

With dual casing strings an inner string is cemented inside the outer string. Typically, this is applied on a long liner lap. The increase collapse resistance is generally higher than that possible from higher weights and grades of casing.

In cases where a competent cement sheath exists between the two strings, the combined collapse rating of the combination exceeds the summed collapse value of the two casings.

Where an incompetent cement sheath exists the combined collapse rating does not exceed the summed rating of the two casings. However, tests reported that 84% of the summed value was the lowest rating, i.e. still a substantial increase in collapse rating.

In instances where a competent cement sheath was present the total collapse rating appeared to be independent of the degree of eccentricity of the two strings. This assumes that a cement sheath exists and the two strings are not in contact.

15.3 Wellhead Loads

Section 9.3.11 contains details of calculating compressive loading on 30” and 20” conductors. . Wellhead compressive loads should be considered for platform and land wells where the wellhead distributes the load directly to the casing.

Where the total compressive loading exceeds the tensile yield strength of the casing or connection, the use of a base plate to distribute the load to an outer casing will be necessary. The design of the base plate will need to take into account any deficiencies in load bearing welds and a design factor of Δ2.0 of the total compressive loads should be used.

Cement between casings can carry some of the loading but for design purposes this should be ignored.

For wells that have no cement between the conductor and surface casing a more detailed analysis is required.

15.4 Cuttings Injection

Cutting re-injection is increasingly being used for environmental reasons to dispose of oil contaminated drilled cuttings. Typically, the cuttings are ground, mixed with seawater and then pumped at low rates through the 13 ⅜” x 9 ⅝” annulus into the formation below the 13 ⅜” shoe.

The design of casing strings for use by cuttings injection should take into account the loads that the annulus may encounter during its operational life. Hydraulic fracturing is complex and requires detailed casing string and wellhead design before

implementation. In addition to the burst collapse and tensile loads that the casing is exposed to, the following issues need to be considered:

Erosion of the wellhead area should always be considered, especially the geometry of the injection entry port. Different cuttings and injection rates can affect the erosion rates.

Erosion of the casing is also a potential problem and should be considered along with the assessment of corrosion. The injection velocity rates are important in considering erosion levels.

Corrosion of casing can occur due to the oxygen content of the seawater used to make up the slurry. Raw seawater is unacceptable for cuttings re-injection. Also bacteria in the water can lead to contamination of the casing. Controlling this by biocide treatment is necessary and should be evaluated.

Cementing of the injection casings is critical to ensure successful re-injection. Good practices including centralisation, optimised cement placement, a stable slurry, good sampling, pipe movement and cement testing all contribute to the future success of re-injection. Properly designed spacers will aid cement placement. The formation can be affected by water-based scavengers and oil-based systems should be considered in order to protect (reduce) the formation fracture pressure.

The deeper the injection shoe (outer casing shoe) the less chance of the cuttings injected contaminating surface horizons. The competency of the casing and cement shoe will reduce the risk of upward migration of fluids.

The top of cement on the outer string should be sufficient to provide a cement sheath in order to prevent migration. Cement to surface should be considered as being the most effective.

The cementing of the inner string is also crucial. If the cement is too high this could risk the re-injection project. If it is too low the injection could be into the wrong horizon. 100 feet of injection spacing is considered to be the minimum distance required.

A port-opening tool may be utilised to circulate contaminated or excess cement. The tool should be placed where the top of cement is required. Also injection can be initiated immediately after cementing to remove annular blockages.

Annulus plugging can be minimised by good injection practices such as displacing the annulus with OBM if there is to be any long term injection shut downs.

The International Association of Oil and Gas Producers (formally the E&P Forum) have produced the following publication which is relevant to planning re-injection systems.

- “Guidelines for the Planning of Downhole Injection Programmes for Oil-based Mud Wastes and Associated Cuttings from Offshore Wells (October 1986)”

This report presents a series of checklists of parameters and concerns to be addressed by the planning engineer.

16 CROSSOVER DESIGN GUIDANCE

Casing crossovers should generally have the same performance rating as the weaker of the components they join together.

Performance properties can be based on the untapered diameters, wall thickness and crossover yield stress and then compared directly with standard casing properties in catalogues.

Where calculations are considered necessary (e.g. to ensure that a supplier understands the expected service conditions) then the calculations should include both the API uniaxial burst calculation, and a triaxial stress calculation.

16.1 Non Uniform Material Properties

The material properties of the cut crossover will depend on the radius of the solid bar from which it was cut. To minimise the problem of property variation, adequate reduction ratio from 'as cast' to forged bar stock is required. Tensile test samples must come from areas of the bar stock relevant in location and orientation to the eventual machined crossover.

16.2 Connections

The section on connections (Section 7) applies equally to crossovers. An extra requirement for crossovers is to keep changes of section away from the connection to avoid stress concentrations additional to those considered during the original design testing and rating of the connection.

16.3 Stress Concentrations

Each time there is a discontinuity of geometry (e.g. a rapid change in diameter, the machining of an O-ring groove, the cutting of a slot, the machining of a radius, the machining of a thread, the drilling of a hole, the creation of a shoulder) the effect is to raise the stress levels local to the discontinuity and results in a "stress concentration". These can be particularly troublesome for shock loads, particularly while running casing. The dimensional guidelines given in this document will minimise stress concentrations and avoid superimposing one stress concentration on another.

In addition, if there is a rapid discontinuity of stiffness where the crossover mates to the next component, the boundary serves as a stress raiser. This is seen when thread specifications limit the wall thickness onto (or into) which the threads are cut. Do not simply thicken the wall of the crossover and expect the crossover to the next component boundary to be stronger. If a female thread wall is radically thicker than the male to which it joins, failure is encouraged on the male side of the boundary.

16.4 Fatigue

Repeated cyclic loading is capable of failing a component even if the stresses are less than the expected failure stress. Significant cyclic loading is not normally seen in casing design but it can occur in tubing, perhaps as a result of violent slug flow, or vibration from a downhole pump. Minimising stress concentrations by following these guidelines should avoid fatigue being more of an issue for crossovers than for casing and tubing.

16.5 Corrosion

Corrosive effects, given time, can cause failure of the crossover, either by stress corrosion cracking, chloride attack, removal of material to cause a stress concentration, or simply raising the nominal stress via material removal. Seek specialist advice if the crossover material is different from the pipe body material as there is a risk of galvanic corrosion between dissimilar materials. Similarly, if the pipe body is plastic-coated internally, it is logical to have a similar finish on the crossover. The same material selection guidelines apply to crossovers as to casing and tubing. Unfortunately, this may mean that crossovers of appropriate material have a long lead time, therefore crossovers need to be considered in the same light as other tubulars in the design and procurement process.

16.6 Abrasion

Where the crossover joins two different diameters of pipe in a flowing situation, there may be areas of high local turbulence. Should the flow have some solids content, abrasive wear rates can be damaging. Typically, thick-walled “flow couplings” are added at points of expected turbulence to withstand abrasion. Ensure the crossover has similar resistance and use gradual tapers to reduce turbulence.

16.7 Component Weakened by Pre-use

Tubing crossovers are often re-used and the use of rig tongs, over-torquing, hammering, or corrosion during storage can contribute to failure. Any crossover, new or used, should be inspected before use, the service history of used crossovers should be available for review.

16.8 Design Control

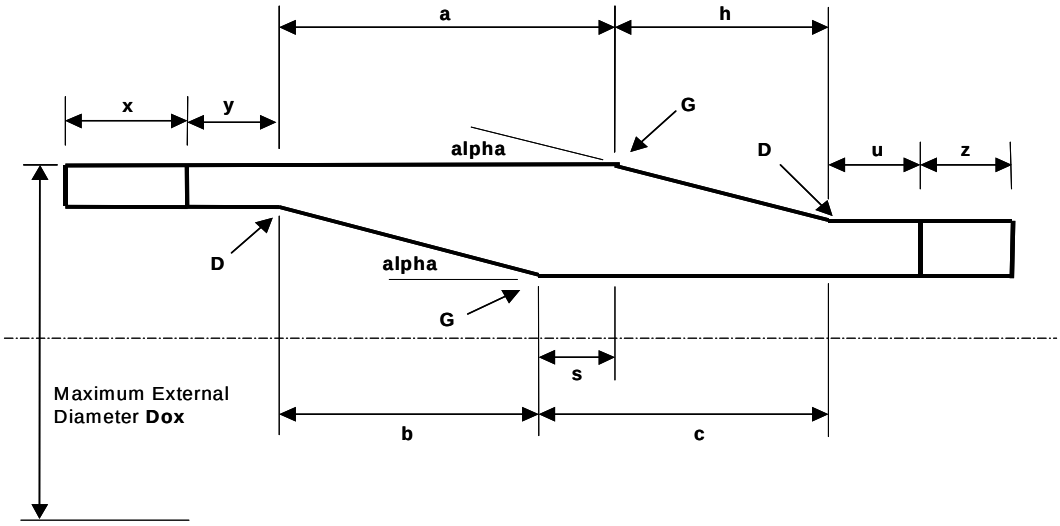
Crossovers require the same attention to design, procurement and handling as the rest of the string. Of particular concern for crossovers are arbitrary design changes (e.g. changes to material specification, or modifications to geometry) to accommodate the convenience or stock availability. Crossovers, like other tubulars, need to be included in the engineering process of demonstrating integrity.

16.9 Crossover Design Checklist

- Ensure the crossover is capable of withstanding the planned nominal loading
- Include temperature de-rating in calculations
- Avoid discontinuities of stiffness and strength by the use of gradual tapers
- Avoid discontinuities of stiffness where the threads of the crossover mate with the next component
- Avoid eddying and erosion by gradual internal tapers
- Use gradual tapers and radiused corners to avoid the crossover hanging
- Reduce stress concentrations by avoiding rapid shoulders, nicks, grooves, slots
- Reduce changes in section to a minimum radius of 15 mm at “depressions” (points D, Fig 16.1, below)
- Separate stress concentration features axially by at least OD/2
- Where a given thread requires a stress relief groove, it must be included
- Limit both external (for external diameter changes) and internal tapers to 10 degrees
- Do not begin, or end, an internal or external taper closer than half a coupling length from the point at which threading stops and the crossover body proper begins

- Do not overlap external and internal tapers. The recommended minimum "stagger" (dimension 's', Fig 16.1) is one third of the maximum crossover diameter
- Ensure the crossover has adequate length and external features to allow the use of make up tools. Should the design call for the possibility of re-cutting threads in order to re-condition a crossover for anticipated further use, ensure adequate length has been allowed originally
- If the crossover has a hydraulic control line allied to it, ensure design consideration is given to it. Special control line clamps are available to protect the control line across the taper where it is vulnerable
- Identify the maximum, minimum and recommended make up torque for the crossover thread connections. Check make up tools and procedure will not over-torque either of the connections
- Ensure the correct material is chosen for the crossover and clearly specified on the drawing. Check material against casing design manual selection guidelines. Ensure traceability of each crossover from original mill material certification through to final inspection. If it hasn't got certification do not use it.

Fig 16.1 Key Dimensions



Check that the change in diameter does not start too close to a connection. Ensure that dimensions y>x/2 and u>z/2.

Avoid upset overlap, always ensure that dimensions: a>b, c>h and "stagger" s>Dox/3.

Ensure that the internal and external taper angles (alpha) are <10 deg and equal.

16.10 Design Factors

Provided the recommendations concerning stagger and taper angle are followed then no special design factors are needed for crossovers. For a tubing crossover completion design factors should be used, for a casing crossover then the Casing Design Manual factors apply, for materials with yield stress of 125 ksi or lower.

16.11 Procurement Requirements

Casing and tubulars should always be purchased following the BG Group Procurement Policy Statement and the Contracting and Purchasing Policy and Quality Control Framework.

16.11.1 Design

The supplier should provide design calculations demonstrating that the cross-over capabilities exceed either the lowest API rating of the adjacent tubulars in burst collapse and tension or that it satisfies some lower loads specifically identified in the purchase order. Where the dimensional guidance above is followed, it may well be that comparison with standard casings rather than actual calculation is all that is required.

Taper angles above 10 degrees internally or more than 10 degrees externally, and overlapping tapers of any angle, require full design calculations to be made.

16.11.2 Vendor Definition of Crossover

To ensure that the vendor fully understands the component to be supplied, a technical specification should be requested to include the following information:

- Scale drawing showing all dimensions
- The connections at each end detailing box/pin, pin/pin etc
- Where the connections will be machined and confirmation that the machine shop is licensed to cut the particular threads
- The material grade and mechanical properties
- What NDT has been performed on the bar stock or forging and what is proposed following machining
- No extra fabrication allowed, i.e. welding without approval from BG
- Details of any additional work other than machining, i.e. heat treatment
- Pressure test procedure
- Short length of adjacent tubulars to allow eyeball check that it ‘looks right’

This sketch can then be passed to the drilling engineer for his review and approval.

Specialist approval must be obtained for heat treatment proposals.

16.11.3 Materials

Impact properties should satisfy the requirements of API 5CT Supplementary Requirements SR16 at -10 deg C or the following:

Yield Stress	Charpy Impact Energy (J)	Test Temperature (deg C)
95 ksi or less	40	-10
110 ksi	50	-10
more than 110 ksi	60	-10

Where crossovers are machined from hot forged stock then a reduction ratio of at least 4 to 1 from as cast should be required to ensure reasonably uniform mechanical properties.

Original mill certification for materials should be requested. Mechanical properties should reference the location of test samples on the forging. Where these are not relevant to the eventual 'as machined' crossover, either because of orientation, location, or expected material anisotropy, additional mechanical testing should be performed on samples from the stock to be machined.

If temperatures above 300^{o}F are expected, then tensile tests at the expected service temperature should be performed.

16.11.4 Inspection

After fabrication, inspection should include MPI (or dye penetrant for non magnetic materials), of threads and section changes, drifting, wall thickness and ovality checks.

16.11.5 Testing

Crossovers should be pressure tested to the lower of the test pressures of the adjacent tubulars, assuming they are different.

16.11.6 Repairs During Fabrication

Any weld repairs and associated heat treatment and inspection during fabrication requires BG approval.

16.11.7 Used Crossovers

If re-using a crossover, check the following:

- What is the service history?
- Is there a unique identification with convincing original mill material certification and tensile data?
- Is material and heat treatment appropriate for service environment?
- Is the thread sizing confirmed by inspection, and if appropriate cut by licensed shop?
- Are inspection records available and visual, drift, and NDT inspection carried out before the job?
- Does the crossover meet the same design criteria as the rest of the equipment supplied?
- Does it meet the guidelines in the rest of this document?

APPENDIX I CROSSOVER DATA SHEET

Type required? :- Pin x Box Pin x Pin Box x Box

Sizes required?

Pin/Box end:- _____Inches OD. X _____lbs./ft.

Connection type:- _____

Box/Pin end:- _____Inches OD. X _____lbs./ft.

Connection type:- _____

API Grade? _____

Length ? _____

Special drift required? _____

If yes, state size _____

Total quantity required? _____

Marking/stencilling requirements _____

Type of thread protectors required? _____

Storage compound (Kendex Orange) Required? _____

Drawing number: - _____ Nb. Drawing must be attached.

Special requirements/Comments: -

Name of Engineer: - _____ Signature: -_____